Northwest Power & Conservation Council
Demand Response Advisory Committee
November 7, 2024

Kevin Smit, NWPCC, began the meeting at 10:00am by greeting members to the DRAC kickoff meeting. Smit introduced Joe Walderman, NWPCC, as the new committee chair and Angela Long, Rockcress Consulting, who has been helping with work. Smit reviewed the agenda and asked Walderman to oversee introductions.

Bonnie Watson, BPA, asked if staff are thinking about any DR or demand flexibility targets for the 9th Plan [Slide 7]. Smit answered that staff don't know yet and that will be talked about after seeing model results. He acknowledged that past work included recommendations and not targets but the final call will be up to Council members.

Tom Smith, PSE, noted that there already some established targets thanks to CETA and other initiatives/requirements. He hoped that any targets that might come out of the 9th Plan would be in line with this existing work. Smit said staff will keep this in mind, pointing to work done by Annika Roberts, NWPCC, to stay abreast of those policies.

Nicolas Garcia, WPUDA, asked if all DR will be treated the same in terms of load and capacity reduction [Slide 9]. He was particularly curious about time of use rates in extreme weather conditions and wondered if there was a uniform expectation for price-based versus technology-based solutions.

Smit said this is the topic for both the rest of the meeting and over the next several months. He said staff will put out numbers that define a resource product and will use many sources including experts from across the country.

Janet Zadra, BC Hydro, asked about negative levelized costs, wondering if they show up because staff is including non-bulk transmission and distribution capacity benefits [Slide 16]. Walderman said yes, they are from transmission distribution deferral value.

Quentin Nesbitt, Idaho Power, confirmed that the costs do not include customer incentives. Walderman said that incentives are included in the costs. Nesbitt voiced surprise. Walderman confirmed, pointing to annual and one-time incentives that are incorporated.

Nesbitt confirmed that the last residential bring-your-own-thermostat program was only $13/kW-yr. Walderman answered yes, when the T&D deferral is incorporated. Nesbitt asked if the T&D deferral is a direct reduction of cost, which means staff is looking at the peak capacity benefit. Smit said this will be further explored later in the presentation.

Garcia asked about cumulative achievable potential and incremental achievable potential both being in MW. He asked if this was at peak or just total, saying total is not as interesting or helpful for some winter peaking utilities, using irrigation as an example. Walderman said this will also be discussed later, adding that the analysis is broken down by region and should provide more insight. He said this is about capacity during the peak times that each product can provide. Smit confirmed that this is relative to the peak so an ag product is relative to summer peak.

Ollis responded to Nesbitt's earlier question saying these 2021 Plan costs have been vetted by the DRAC and that's the goal for the 9th Plan as well.

Leona Haley, Avista Corp, wrote, How do you handle competing DR products? Either/or but not both. in the question pane. Ollis said they are trying to improve the modeling to capture these things, pointing to the new capital expansion model. He said the last plan did not have enough capability and this Plan will have more, but this will still require discussion.

Ted Light, Lighthouse Energy, wrote, Usually, only a portion of the incentives are included in the TRC levelized cost calculation. This is intended to represent the inconvenience incurred by the end use customer. in the question pane. Smit agreed, saying this will also be discussed.

Long noted that the numbers on the slide represent the 2021 Plan and assumptions will be updated and expanded. She highlighted that the DRAC surveys are important to this effort.

Scott Reeves, Resource Innovations, asked for a breakdown of components that go into these, particularly ones that are being treated as benefits besides a T&D deferral. Smit said this will be discussed but didn't know of anything offhand. Ollis recalled that the T&D deferral is the only benefit in the supply curve cost but there is another benefit that happens in the modeling.

Frank Brown, BPA, noted that there was a lot of attention to the interaction between EE and DR in the supply curves in the last Plan adding that there is always room for a deeper look.

Jennifer Finnigan, SCL, asked to what extent these costs and ramp rates reflect existing infrastructure, noting that many utilities are in the pilot stage or can't apply them at all. She wondered if the model would reflect that. Walderman didn't think the model did but said this is an interesting topic to explore. Ollis added that the last few Plans acknowledged differences in infrastructure but wasn't sure about the extent of it. He said this Plan will offer an opportunity to dig in further.

T. Light discussed battery programs saying there seems to be two different use cases with different cost and incentive structures. He said one is a limited use/peak demand only application while the other is more of a daily arbitrage operation. T. Light suggested splitting costs and incentives that way, noting that daily use will show more wear and tear on the battery.

T. Light then talked about behavioral/peak time rebates, saying he had no concern with adding them, but cautioned against the potential for some programs to compete for the same pool of participants. He said some programs have fixed costs that are spread over a number of participants so as you add programs, you're subtracting participants to spread those costs over. Smit noted that last time there were a lot of high cost/not cost-effective programs that could drop out.

Finnigan asked how often staff plan to conduct surveys. Walderman answered annually. Smit agreed, saying it will not be as detailed as the RTF's conservation progress report.

Haley wrote, The supply curves should also represent any load shifts pre and post event, such as preconditioning and snap-back. in the question pane [Slide 27]. Smit wrote, Yes, agreed. I think Joe has a slide on that coming up. We are looking to define each resource as a "shift" or "shed" where the shift refers to those products that reduce load at one time but gain it back again later (or earlier).

Garcia appreciated the new zonal direction staff is taking, but said when it comes to DR a full requirements BPA customer doesn't get to see hour-to-hour price changes. He acknowledged the next contract could change things but called for caution when assuming a trading floor market price is the same as a price these utilities will see.

Ollis agreed that this a major concern and there has already been good discussion around it. He thought the model should still show what's possible. Ollis said there should be more discussion but did not think it should change what's possible in the modeling. Garcia said the Plan will create expectations through state laws and a utility may institute and spend money on a DR plan. But he continued, if that utility is not getting the proper signal, they will never pull the lever, and it will not be cost effective. Garcia said this brings up a question about defining cost effectiveness if the signal is never sent.

Ollis agreed this should be a separate conversation, calling it a contractual and not physical barrier. He said cost effectiveness has a slightly different definition at the Council and should be discussed as well.

Reeves wrote, One additional non-res program for consideration: Auto-DR for lighting and/or HVAC (assume this is distinct from curtailment or DLC), in the question pane. Smit thanked him.

Fred Heutte, NW Energy Coalition, commented that things are changing, noting that moving to an hourly rather than quarterly model will highlight the value of DR. He noted that the region is moving to a day-ahead market which pulls further away from the outmoded block product approach at Mid-C and will give a much better view to the value of DR.

Heutte then said even if BPA and public power utilities don't experience the same tight conditions that the IOUs do, this presents an opportunity for public power to do DR at a high value and get paid by the IOUs. He said this is a complicated future with new opportunities.

Garcia agreed with Heutte completely and totally, but said he wasn't concerned about demonstrating value but in turning that value into action. He said that price signal must flow back to the utilities so they can pull the lever, asking if they will get that. Heutte agreed with Garcia saying the big issue is BPA doesn't have a clear plan for how their preference customer utilities can be in the markets.

T. Light wrote, Re: price signal for BPA's full requirements customers, these customers do pay monthly demand charges of ~$10-15/kW in peak winter and summer months. It is not the same price signal that other utilities may see, but it is not nothing, in the question pane.

Brown said we have the rates but it's $1-2 a month because all the peak load is excluded from the demand charge. Brown echoed Garcia's comment, saying a $4/month demand charge saw a lot of DR on winter mornings but that stopped with a $1 charge. Brown said a price signal of $20-40 a year causes action while $12 a year doesn't. He then said the slice and block customers, which represent 40% of load, receives no demand charge from BPA.

Smit said this will be a good topic for future meetings.

T. Light said BPA's most recent DR potential work pulled aside a separate set of products that were frequently used and had some load shifting characteristics. He said they binned by hourly shapes that incorporated load shifting and demand reduction instead of providing annual MW of demand reduction and number of events.

Watson said she will be sharing information soon.

Nesbitt wrote, Our experience is that our programs have both shifting and shedding embedded and that it depends on the customer and weather, in the question pane. He said they have done binning by pricing or behavioral, or types of programs that are restricted by hours and those that are not.

Haley wrote, A couple of the programs you moved from Shift to Shed I disagree with. For instance, AC switch. Maybe there's no pre-cool, but there's a snap back, with some systems never catching up, which causes higher use for the customer after the event, in the question pane.

Smit urged DRAC members to fill out and send in the survey by the end of November [Slide 33].

T&D Deferral and the 0th Power Plan
Tomás Morrissey, NWPCC

Blake Sherer, Benton PUD, wrote, is there a known reason why PGE and PSE values are so much higher than others? in the question pane [Slide 13]. Smit responded, They have significant transmission constraints and need for more power, and It sounds like there may also be some methodology differences.

Nesbitt also noted the large differences in values between utilities, wondering why that was the case. Tomás Morrissey, NWPCC, said he noticed the differences too, pointing to differences in methodology. He said staff is hoping to see some smoothing from taking the averages and from using an east/west split.

Rob Del Mar, ODOE, shared information about wildfire lawsuits and Pacific Power, wondering if staff has considered litigation like this. Morrissey wasn't sure but pointed to survey questions about load growth.

Garcia said he's heard arguments in wildfire cases stating that the utility was imprudent because they had bare wires that should have been wrapped. He didn't know if this would become the new norm but thought the effect could see a tremendous amount of replacement. Garcia said this is something to watch.

Josh Rushton, RTF CAT, said if you have to replace these lines anyway that portion of the distribution or transmission would already be sunk costs with incremental cost beyond that. Morrissey agreed, referring to survey results on [Slide 10] that try to control for this.

Heutte wrote, I have to leave right away but generally support the direction on avoided T&D and will contact Council staff for more discussion . . . thx, in the question pane.

Smit thanked the DRAC for their participation. Walderman appreciated the feedback and looked forward to future meetings.

Smit ended the meeting at 12:00pm.

Attendees via Zoom Webinar

Kevin Smit	NWPCC
Jennifer Light	NWPCC
Joe Walderman	NWPCC
Tomás Morrissey	NWPCC
Hayden Reeve	PNNL
Jake Wise	PGE
Brittainy Pond	PSE
Frank Brown	BPA
Sarah Widder	Cadeo Group
Blake Sherer	Benton PUD
Aaron James	NEEA
Kari Montrichard	BC Hydro

Mark Jerome	CLEAResult
Andrew Willard	NISC
Kitty Wang	Energy Solution
Christina Steinhoff	NEEA
Robin Maslowski	Trillium Energy
Paul Koenig	WA UTC
Malcolm Ainspan	NRG
Heather Nicholson	Orcas Power & Light
Haley Ellett	Hood River
Paul Lee	independent
Amber Gschwend	GDS Assoc.
Sophia Spencer	Nauvoo Solutions
Jeff Harris	NEEA
Nathaniel Nichol	independent
Ahlmahz Negash	Tacoma Power
Bryce Yonker	Grid Forward
Todd Myers	WA Policy
Suzanne Frew	Snohomish PUD
Nolan Kelly	BPA
Zeecha Van Hoose	Clark PUD
Quentin Nesbitt	Idaho Power
Matt Babbitts	Clark PUD
Rob Del Mar	ODOE
Bonnie Watson	BPA
Ted Light	Lighthouse Energy
Angela Long	Rockcress Consulting
Josh Rushton	RTF CAT
John Ollis	NWPCC
Janet Zadra	BC Hydro
Nora Hawkins	WA Dept of Commerce
Tom Smith	PSE
Scott Reeves	Resource Innovations.
Fred Heutte	NW Energy Coalition
Michael Swanson	CLEAResult
Jennifer Finnigan	SCL
Annika Roberts	NWPCC
Nicolas Garcia	WPUDA
Kerry Meade	Building Potential
Leona Haley	Avista Corp
Laura Thomas	NWPCC
Elizabeth Osborne	NWPCC